PUBLIC SERVICE COMMISSION OF WISCONSIN

Memorandum

October 30, 2009

TO: The Commission

FROM: Robert Norcross, Administrator
Mary McIlwee, Docket Coordinator
James Wottreng, Audit Manager
Gas and Energy Division

RE: Joint Application of Wisconsin Electric Power Company and Wisconsin Gas LLC, both d/b/a We Energies, for Wisconsin Electric Power Company to Increase its Electric, Natural Gas and Steam Rates and for Wisconsin Gas LLC to Increase its Natural Gas Rates — 5-UR-104

BRIEFING MEMORANDUM

STATEMENT OF THE PROCEEDING

This rate case considers a joint application that Wisconsin Electric Power Company (WEPCO) and Wisconsin Gas Company (WG) filed on March 13, 2009. WEPCO's application covers each of its four utility operations separately: its electric operations (WE Electric), its natural gas operations (WE-GO), its downtown Milwaukee steam operations (DMS), and its Wauwatosa steam operations (WS). In this memorandum, any reference to WG and the four utility operations under WEPCO, collectively, will use the general name "We Energies" and any reference to the holding company, Wisconsin Energy Corporation, will use the acronym "WEC." WEPCO requested a $189.7 million (7.5 percent) Wisconsin jurisdictional revenue deficiency for electric operations, a $38.8 million (4.6 percent) revenue deficiency for WG's operations, a $22.1 million (3.6 percent) revenue deficiency for the WE-GO and revenue deficiencies of slightly more than $1 million for each of the DMS and WS steam utilities.

On June 25, 2009, a prehearing conference was held to determine the issues that will be addressed in this docket and to establish a schedule for the hearing. On September 30, 2009, technical hearings were held in Madison. On September 29, 2009, public hearings were held in Madison, Milwaukee, Racine, and Appleton. Because of the high level of interest in this proceeding demonstrated at the Milwaukee location and because technical problems in Milwaukee made participation inconvenient to those in attendance, a second public hearing session was held on October 21, 2009.

Simultaneous briefs and reply briefs were filed with the Commission on October 16, 2009, and October 23, 2009, respectively.

This briefing memorandum provides background and discussion of each party's position on select contested issues, based on the record in this proceeding as well as briefs filed by parties. This memorandum also presents alternatives for each of these select contested issues, including a discussion of each alternative. Other issues shown in the decision matrix are listed in this memorandum. For these issues, further discussion in addition to the decision matrix is not considered necessary.

1. What electric residential sales forecast is appropriate for the test year?

Discussion

In their filings, WEPCO included sales forecasts of electricity, specifically WEPCO, as is normal with all rate filings. In supplemental direct testimony, filed in July 2009, the applicants presented new estimated levels for test year sales, for both electricity and natural gas. Specifically, a decline in electricity sales in total was shown of 1,022,300 MWh. (Gaughan, Tr. SD1.6:16-18, SD1.7:6-9). Commission staff accepted the updated test year sales forecast for General Primary and General Secondary electric customers, and included such sales reductions of 853,000 MWh in the Commission staff test year electric sales forecast. Commission staff did not accept the applicants' new estimated electric residential sales, which was a decline of 169,300 MWh compared to their filing. In rebuttal testimony, the applicants provided information illustrating electric usage per customer, and recapped what was included in supplemental direct testimony. (Gaughan, Tr. R1.25:5-14.)

In surrebuttal testimony, Commission staff witness Mr. Wottreng provided more detail and explanation why the residential sales decline was not incorporated into the Commission staff estimate of electric test year sales. Specifically, stronger housing starts in 2008 were illustrated (Wottreng, Tr. SR11.1-SR11.2), historical sales were presented (Wottreng, Tr. SR11.2) that shows the original residential sales forecast was representative, and why incorporating information from August, 2009, would not be appropriate, as such information was unaudited (Wottreng, Tr. SR11.1.)

In sur-surrebuttal testimony, Mr. Gaughan testified that the August 2009 information was just to bolster the new estimates, and that differences noted by Commission staff in some of the new information were superficial. (Gaughan, Tr. SSR1.10-SSR1.11.)

Alternatives

Alternative One: Do not adjust WEPCO's filed estimate of residential electric sales.

Alternative Two: Adjust WEPCO's filed estimate of residential sales.

2. Is it appropriate to defer the effects of lost sales, and recover such impacts in future test years?

Discussion

As noted above, in July 2009, WEPCO presented a new electric sales forecast that showed continuing sales erosion, particularly among industrial and commercial customers. Accepting such declines would result in an increase of $55 million in WEPCO's revenue deficiency. (WIEG Init. Br. at 3) WIEG provided information about what this Commission did in extraordinary economic times during the Great Depression and the Second World War in its initial brief that shows the Commission could grant "temporary reduction to rates….face a unique emergency situation." (WIEG Init. Br. at 5) WIEG goes on to recommend that the Commission defer the impact of declining sales into a future test period. (Kollen, Tr. D2.37-D2.40; WIEG Init. Br. at 6) The applicants do not support this recommendation. (Ackerman, Tr. R1.26:1-20) Charter Steel does not support this recommendation as well (Charter Steel Init. Br. at 2)

Alternatives

Alternative One: Defer all costs of declines in residential, commercial and industrial sales, accepting that such declines are due to the economic downturn and are extraordinary. These deferred costs would be issues in later rate cases.

Alternative Two: Do not defer any declines in sales being experienced by the company, and treat the test year sales forecast as such forecasts have been treated in the past.

3. Should the Commission deny the revenue requirement impact of declining sales?

Discussion

In its testimony, WEPCO presents new information regarding lost sales that represent approximately $50 million in increased revenue deficiency if accepted by the Commission. (Ertl, Tr. D12.4-D12.5) It is Charter Steel's position that WEPCO should deal with the sales loss like any other publicly held company through various efforts including but not limited to cost reductions and a reduction in the dividend paid to stockholders. (Ertl Tr. D12.5) Charter Steel goes on to state in testimony that on-going rate increases due to lost sales only exacerbate the issue and the speed with which sales are lost. If the lost sales request is approved utilities will no longer look to increased customer sales to drive income and stockholder returns. Instead income and returns will be driven by obtaining rate relief from lost sales. (Ertl, Tr. SR12.2-SR12.3)

Alternatives

Alternative One: Use traditional rate setting treatment and reflect the test year sales forecast, using present rates to compute revenues.

Alternative Two: Direct the utility to perform more cost cutting and budget adjustments across the board to decrease the requested revenue adjustment needed.

Alternative Three: Ask applicants to voluntarily decrease their revenue deficiency request regarding this issue.

4. What estimate of employee position vacancies for 2010 should be incorporated into the electric, natural gas, and steam utility revenue requirements?

Background

Commission staff proposed that the test year estimated payroll expense be reduced to reflect an estimate of the budgeted employee positions that will be vacant during the test year.

Discussion

Commission staff witness James Wottreng testified that the test year vacancy level was derived by comparing budgeted full-time equivalent (FTE) positions to actual FTE positions at April 2009. The application of this actual vacancy level to the test year resulted in a net 283 position reduction, reducing payroll expense by $15.2 million. (Wottreng, Tr. D11.6)

The applicants' witness David Ackerman testified that the April 2009 actual to budget staffing variance reflected actions taken by the company in response to the financial consequences being experienced due to lost sales related to the recession. Thirty-four of those April vacancies related to Power the Future generation facilities, 19 of which were filled the next month and all of which are essential for the safe and reliable operation of new generation facilities. The total income statement expense for these positions is estimated to be $2.6 million.

Mr. Ackerman testified that 43 electric line mechanics and 35 customer service technicians are likely to retire over the next three years. Since the apprenticeship training programs for these positions require four years, the company would fall short of having qualified and capable employees ready to replace the expected retirees over the next several years. To avoid such an outcome, the company proposes that 49 of the positions that Commission staff's proposal would eliminate be added back to Wisconsin Electric's test year payroll. The total income statement expense for these positions is estimated to be $3.7 million.

Mr. Ackerman further testified that, combined with the company's strategy to shift more of WG's gas distribution work to internal labor from the use of contractors, Commission staff's proposed vacancy adjustment would result in an insufficient total budget to perform required work. Commission staff's proposed payroll adjustment, combined with its proposed inflation adjustment for the non-labor component of WG's gas distribution costs, yields a gas distribution total budget that is $0.9 million less than 2008 actual. The company believes as a minimum, WG's 2010 gas distribution budget in total should at least be equal to 2008 actual adjusted to reflect two years of inflation. To achieve this result, the company proposes restoring 22 positions to WG. The total income statement expense for these positions is estimated to be $1.4 million. (Ackerman, Tr. R1.16-R1.20, Ex. 63)

Mr. Wottreng testified that though a single point in time had been used for the estimate of the test year vacancy level, the actual to budget staffing variance for calendar year 2008 had been worse. The actual to budget staffing variance was 341 positions on average for 2008 and was 301 positions for January 2008. These vacancy levels indicate a persistent actual to budget staffing issue and that the April 2009 variance of 283 may not merely be a reflection of company actions taken in response to lost sales. The reliability concerns that the company expresses for the test year would also be relevant to actual to budget staffing variances seen historically. (Wottreng, Tr. SR11.4-11.5)

Alternatives

Alternative One: An employee position vacancy level of 178 FTE positions for 2010 should be incorporated into the electric, natural gas, and steam utility revenue requirements.

Alternative Two: An employee position vacancy level of 283 FTE positions for 2010 should be incorporated into the electric, natural gas, and steam utility revenue requirements.

Alternative Three: An employee position vacancy level, as determined by the Commission, for 2010 should be incorporated into the electric, natural gas, and steam utility revenue requirements.

5. What percentage wage increase for 2010 for management employees should be incorporated into the electric, natural gas, and steam utility revenue requirements?

Discussion

Commission staff witness Mr. Wottreng testified that the test year payroll expense for management should reflect no wage increase for 2010. In proposing no pay increase for management for 2010, he considered a number of factors. Two of those factors were the inflation estimates and the company's estimated 3.0 percent average pay increase for management for 2009. Based on the June 2009 economic forecast that Commission staff receives, Commission staff's inflation estimates were a negative 0.5 percent and a positive 1.9 percent for 2009 and 2010, respectively, or 1.4 percent for the two-year period. (Wottreng, Tr. D11.6, D11.11, SR11.5)

The applicants' witness Mr. Ackerman testified that Commission staff's proposed increase of zero for 2010 effectively means no increase over the two years of the company's biennial period, that the company must compete in the overall labor market to attract and retain quality employees, and that the human resources consulting firm Watson-Wyatt poll indicated that companies plan median merit increases of 3.0 percent for 2010. The company believes that the expected 2010 median increase of 3.0 percent indicated by the Watson-Wyatt poll for its management employees is appropriate. (Ackerman, Tr. R1.21-R1.22)

Alternatives

Alternative One: A 3.0 percent wage increase for 2010 for management employees should be incorporated into the electric, natural gas, and steam utility revenue requirements.

Alternative Two: No wage increase for 2010 for management employees should be incorporated into the electric, natural gas, and steam utility revenue requirements.

Alternative Three: A wage increase, as determined by the Commission, for 2010 for management employees should be incorporated into the electric, natural gas, and steam utility revenue requirements.

6. What percentage wage increase for 2010 for union employees not under existing contract should be incorporated into the electric, natural gas, and steam utility revenue requirements?

Discussion

Commission staff witness Mr. Wottreng testified that the test year payroll expense should reflect a 1.9 percent wage increase for 2010 for union employees not under existing contract. Based on the June 2009 economic forecast that Commission staff receives, Commission staff's inflation estimate was 1.9 percent for 2010. (Wottreng, Tr. D11.6, D11.11, SR11.5)

The applicants witness Mr. Ackerman testified that the most recently negotiated union increases within the company were 3.0 percent and 3.1 percent for 2010. The company believes that the increase for union employees not under contract in 2010 should be set at 3.0 percent to be comparable to the recently negotiated levels. (Ackerman, Tr. R1.23)

Alternatives

Alternative One: A 3.0 percent wage increase for 2010 for union employees not under existing contract should be incorporated into the electric, natural gas, and steam utility revenue requirements.

Alternative Two: A 1.9 percent wage increase for 2010 for union employees not under existing contract should be incorporated into the electric, natural gas, and steam utility revenue requirements.

Alternative Three: A wage increase, as determined by the Commission, for 2010 for union employees not under existing contract should be incorporated into the electric, natural gas, and steam utility revenue requirements.

7. Should the operation and maintenance (O&M) impact including payroll taxes relating to a 2.0 percent furlough for all employees be incorporated into the electric, natural gas, and steam utility revenue requirements?

Background

Commission staff proposed that the test year estimated O&M payroll expense be reduced to reflect a furlough adjustment. This is a potential adjustment that is not reflected in Commission staff's test year estimates. Commission staff is proposing this potential adjustment in each of the current investor-owned utility rate proceedings.

Discussion

Commission staff witness Mr. Wottreng testified that the net O&M impact plus payroll taxes of a 2.0 percent furlough for all employees would be a reduction to test year expenses by an additional $6.3 million. Though the potential adjustment is labeled as a furlough adjustment, it does not prescribe the method, or methods, by which the company attain the proposed cost reduction. (Wottreng, Tr. D11.7, SR11.5)

The applicants witness Mr. Ackerman testified that the company's union contracts would not allow furloughs, so any attempt to institute a furlough would likely face a legal challenge. A regulated utility has a mandate to provide an essential service on demand and the company must always be staffed appropriately for operation and possible emergency maintenance work. Furthermore, the company has reduced its base workforce by 10 percent, or 519 positions from December of 2004 through April of 2009 and it is unreasonable to propose an arbitrary furlough on top of what is already a down-sized workforce. (Ackerman, Tr. R1.20-1.23)

Alternatives

Alternative One: Do not include the O&M impact including payroll taxes of a 2.0 percent furlough for all employees into the electric, natural gas, and steam utility revenue requirements.

Alternative Two: Include the O&M impact including payroll taxes of a 2.0 percent furlough for all employees into the electric, natural gas, and steam utility revenue requirements.

8. Is it appropriate to include WEC Board of Director costs allocated to the utilities in the electric, natural gas, and steam utility revenue requirements?

Alternative One: Include WEC Board of Director costs allocated to the utilities in the electric, natural gas, and steam utility revenue requirements.

Alternative Two: Do not include WEC Board of Director costs allocated to the utilities in the electric, natural gas, and steam utility revenue requirements.

9. Is it appropriate to include in this proceeding costs related to the WPDES settlement agreement?

Alternative One: Include in this proceeding $5,382,000 for costs related to the WPDES settlement agreement.

Alternative One: Do not include in this proceeding costs related to the WPDES settlement agreement

10. Should the June 17, 2009, update provided by Towers Perin related to Post Retirement Medical, Non-Qualified Pension, and Qualified Pension costs be incorporated into the electric, natural gas, and steam utility revenue requirements? (Uncontested)

11. Should an updated 2010 estimate of the ATC transmission expense amounts be included in the final electric revenue requirement? (Uncontested)

12. Should an updated transmission levelization amount for the year-over-year increase between 2010 and 2011 be included in the final electric revenue requirement? (Uncontested)

13. Should Commission staff's proposed inflation adjustment be updated with the most recent available inflation estimate?

Alternative One: Do not update Commission staff's proposed inflation adjustment with the most recent available inflation estimate.

Alternative Two: Update Commission staff's proposed inflation adjustment with the most recent available inflation estimate.

a. If the Commission staff's proposed inflation adjustment should be updated, what inflation forecast should be used for that update?

Alternative One: Update Commission staff's proposed inflation adjustment based on the October 2009 Commission staff inflation estimates.

Alternative Two: Update Commission staff's proposed inflation adjustment based on the most recent available Blue Chip Financial Forecast inflation estimate.

14. If new depreciation rates are not approved in docket 05-DU-101 to be effective prior to, or concurrent with, the implementation of new base rates in this proceeding, should the current depreciation rates be incorporated into the electric, natural gas, and steam utility revenue requirements? (Uncontested)

15. Should an option for a limited reopener or deferral accounting treatment be approved for WE Electric in the event that governmental mandates resulting from the Governor's Global Warming Task Force result in incremental costs or declines in sales? (Uncontested)

16. What accounting and rate treatment should be given the domestic production activities deduction under Section 199 of the Internal Revenue Code that is currently being escrowed? (Uncontested)

17. Should an eight-year amortization period, instead of a four-year period, be used for five electric utility regulatory asset accounts as proposed by the company? (Uncontested)

18. Should the company be authorized to accrue AFUDC on 100 percent of CWIP associated with three electric utility projects; the Oak Creek Air Quality Control System, the Edgewater 5 Selective Catalytic Reduction and the Glacier Hill wind turbine? (Uncontested)

a. Should a current return on 50 percent of all other electric, natural gas and steam utility CWIP be authorized? (Uncontested)

19. Should continuation of the Low Income Pilot program be extended beyond March 2010 to December 31, 2011? (Uncontested)

20. Should continuation of the use of escrow accounting for residential bad debt expense be extended beyond March 2010 to December 31, 2011? (Uncontested)

21. Should Commission staff's other audit adjustments be included in the final electric, natural gas, and steam revenue requirements approved in this proceeding? (Uncontested)

22. Should $4,422,000 of estimated Wisconsin jurisdictional O&M costs associated with Elm Road Generating Station (ERGS) Unit 2 be deferred until 2011?

Alternative One: Yes.

Alternative Two: No.

23. Should $5,305,000 of estimated Wisconsin jurisdictional O&M pension costs be deferred?

Alternative One: Yes.

Alternative Two: No.

24. Should WE Electric be allowed a current return on the deferred amounts? (Uncontested)

25. Excess Capacity

WEPCO has excess capacity for 2010 and thereafter due to the recent addition of the Port Washington and Elm Road power plants along with a significant reduction in load resulting from the current recession. There are three issues concerning the excess capacity: (a) Sale of Excess

Capacity, (b) Mothballing of Certain Generating Units, and (c) Statewide Collaborative on Excess Capacity.

a. Should WEPCO be required to update the Commission and the parties in this docket on the ongoing marketing of excess capacity?

Discussion

WEPCO witness Mr. Schumacher testified that the company has sold and is planning to sell excess capacity for the 2010 test year through short-term sales to Midwest Independent Transmission System Operator (MISO) participants and bilateral transactions. Mr. Schumacher testified that the test year estimate for the sale of excess capacity is $6.6 million. (Schumacher, Tr. 87R-88R)

The Citizens' Utility Board (CUB) witness Mr. Hahn testified that WEPCO has provided information describing some of its efforts to market the excess capacity. However, the company has not provided documentation showing that the estimated sales of excess capacity provide a net benefit to ratepayers. Mr. Hahn testified that the Commission should require WEPCO to demonstrate that these sales of excess capacity provide net benefits to ratepayers and the Commission should require WEPCO to provide documentation describing the steps the company has taken to address its excess capacity situation to minimize costs to ratepayers. (Hahn, Tr. D3.55-D3.57)

Mr. Schumacher testified that the sales of excess capacity forecasted for the 2010 test year are short-term, capacity-only sales. (Schumacher, Tr. SSR1.14) Mr. Schumacher testified that two generic types of power sales do provide net benefits to customers. The sale of a capacity-only product, under a short-term (less than three years) basis, provides net benefits to customers because the proceeds from the sale directly reduce monitored fuel costs.
Mr. Schumacher testified that sales for resale under WEPCO's formula rate provide net benefits

to existing ratepayers by the allocation of fixed costs to wholesale customers. (Schumacher, Tr. R1.78p–R1.79p)

For a utility in an excess capacity situation any revenue received from the sale of excess capacity will result in reduced costs to existing ratepayers through lower monitored fuel costs for short-term capacity sales and for any long-term capacity and energy sale that is treated as a fully allocated sale in the jurisdictional cost-of-service study. WEPCO should keep the data and analysis of the options available to the company for the sale of excess capacity to support that it has selected the best option for its ratepayers. This analysis will be important when WEPCO is nearing its planning reserve margin, currently at 14.5 percent for 2010.

Alternatives

Alternative One: WEPCO does not need to file additional information to support its sales of excess capacity benefit ratepayers.

Alternative Two: WEPCO is required to file additional information to support its contention that sales of excess capacity benefit ratepayers, and it must file a report within six months of the date of the Final Decision in this proceeding describing the steps the company has taken to address its excess capacity that minimizes costs to ratepayers.

b. Would mothballing of certain WEPCO's generating units result in lower 2010 fuel and purchased power costs?

Discussion

Mr. Hahn testified that WEPCO should be required to analyze the option of mothballing generating units (specifically, Presque Isle Units 5 and 6) to determine if fuel and purchased power costs can be lowered for the test year. Mr. Hahn testified this evaluation should be filed with the Commission and parties 90 days after the issuance of the order in this proceeding. (Hahn, Tr. D3.61, SR3.25)

Mr. Schumacher testified that mothballing units can be an effective option for units not needed for maintaining electric system reliability. However, the fixed costs are already assigned to Presque Isle Units 5 and 6 for 2010. In addition, given the delay to request and conduct the necessary MISO reliability studies prior to commencing this mode of operation, minimal fuel savings would be achieve in 2010 if the units are determined not to be needed to maintain system reliability. (Schumacher, Tr. SSR1.16) Mr. Schumacher testified that the company expects the profitability concerns for several of its units are of a short-term nature and that the units will return to historic levels of profitability. (Schumacher, Tr. R1.84)

Alternatives

Alternative One: WEPCO should not be required to file an evaluation of the benefits of mothballing some generating units 90 days after the issuance of the Final Decision in this proceeding.

Alternative Two: WEPCO should be required to file an evaluation of the benefits of mothballing some generating units 90 days after the issuance of the Final Decision in this proceeding.

c. Should the Commission initiate a statewide collaborative process to assess the surplus capacity in Wisconsin and develop solutions that benefit ratepayers?

Discussion

Wisconsin utilities have excess capacity through 2012 based on the Strategic Energy Assessment Final Report issued by the Commission in April 2009. In this proceeding it is estimated that WEPCO will be in an excess capacity position through 2018. WEPCO has provided information in this case explaining activities undertaken to reduce its excess capacity position.

Mr. Hahn testified that a collaborative statewide effort to develop a solution that maximizes the utilization of surplus capacity to the benefit of ratepayers may result in a better outcome than the sum of the individual efforts of the Wisconsin utilities. The collaborative effort should involve all of the Wisconsin utilities and other stakeholders that results in specific action plans with a mechanism for appropriately sharing benefits identified in the collaborative. The action plans should include coordinated purchases and sales, mothballing or retiring certain units, and swaps and exchanges of capacity and energy. (Hahn Tr. D3.66-D.367) Mr. Hahn testified that without the collaborative effort utilities will continue to try to solve the surplus capacity problem via isolated activities, increasing the likelihood that a joint solution involving two or more utilities will not be identified. (Hahn, Tr. SR3.22)

Mr. Schumacher testified that WEPCO does not support Mr. Hahn's proposed collaborative approach for addressing the surplus capacity problem in Wisconsin because the collaborative effort is impractical and that he was informed the collaborative effort may raise antitrust issues. Also the other utilities are competitors of WEPCO for either the sale of capacity or for longer-term wholesale transactions. (Schumacher, Tr. R1.79)

Alternatives

Alternative One: The Commission does not accept Mr. Hahn's proposal to initiate a statewide collaborative effort to address the surplus capacity problem in Wisconsin.

Alternative Two: The Commission accepts Mr. Hahn's proposal to initiate a statewide collaborative effort to address the surplus capacity problem in Wisconsin.

26. Should the heat rate input for the PROMOD model in this case be the same heat rate used in the EGEAS model in the Edgewater 5 proceeding?

Background

Mr. Schumacher testified that WEPCO uses the PROMOD security-constrained production cost model to project how its generating resources would be utilized in 2010 under MISO dispatch. (Schumacher, Tr. 77R) Mr. Hahn testified that a comparison of full load heat rates in the EGEAS model used in the Edgewater 5 proceeding had some significant differences from the full load heat rates in PROMOD in this case. (Hahn, Tr. D3.63)

Mr. Hahn testified that using the full load heat rates from EGEAS for the Presque Isle and the Port Washington units without rerunning the PROMOD model (keeping the dispatch the same) would lower 2010 fuel costs by approximately $9 million. (Hahn, Tr. D3.64) Mr. Hahn testified if both PROMOD and EGEAS included the same set of WEPCO generating units, the inputs such as heat rates, emission levels, etc., should be the same. The heat rate of a unit does not normally change by very much, so there is no reason not to have the same data in both models. (Hahn, Tr. SR3.23)

Mr. Schumacher testified that WEPCO strives to maintain consistent data in its cost models. “The PROMOD data base is originally generated by a third party, Ventyx, and is modified by WEPCO to be consistent with current operating conditions.” Mr. Schumacher testified, “Having accurate-up-to-date heat rates in PROMOD is essential for developing representative dispatch levels for the Company’s units, and corresponding monitored fuel costs.” (Schumacher, Tr. R1.80-R1.81)

Alternatives

Alternative One: The heat rate used by WEPCO in its PROMOD runs is appropriate to project generating resources that would be utilized in 2010 under MISO dispatch.

Alternative Two: The heat rate used in the EGEAS runs in the Edgewater 5 proceeding is the appropriate heat rate to be used for 2010 in the PROMOD dispatch.

27. Uneconomic Dispatch – Must Run Designation and Additional Coal Burn of Excess Colorado Coal

a. Should 2010 fuel costs be reduced by $1.6 million to reflect the elimination of must run designation in the PROMOD model for Presque Isle Units 5 and 6?

Background

WEPCO and CUB have a disagreement on the number of WEPCO-owned generation units that are designated as must run in the PROMOD dispatch model, specifically the must run designation for Presque Isle Units 5 and 6.

Discussion

CUB witness Mr. Hahn testified that for the majority of its fossil units WEPCO has designated, for at least a portion, each unit's output as must run in the PROMOD model. "Designating units as Must Run may cause uneconomic dispatch, for which there could be no make whole payments." (Hahn, Tr. D3.58) Mr. Hahn testified a savings of $1.6 million would be realized from changing the must run designation for the Presque Isle Units 5 and 6. Mr. Hahn testified that if the company believes that not designating the units as must run would result in excessive starts and stops that would have an adverse effect on unit longevity and reliability, the company should provide evidence that such starts and stops will result in premature failure and higher forced outage rates. (Hahn, Tr. SR3.23C – SR3.24C)

WEPCO witness Paul Schumacher testified, "The Company's goal in modeling its unit operations with PROMOD is, to the extent possible, to replicate actual unit operations within the MISO energy market." Mr. Schumacher testified, "The must-run designation is designed to minimize, to extent possible, MISO decommitment and subsequent shutdown/startup during off-peak periods when the variable cost of units may not be supported by system LMP. Frequent shutdown/startup of coal units causes thermal cycling of units, which in turn leads to premature failure and higher forced outage rates." (Schumacher, Tr. R1.82p) Mr. Schumacher testified that the $1.6 million savings in fuel would be more than offset by an increase in O&M and capital costs of the units. (Schumacher, Tr. SSR1.16)

Alternatives

Alternative One: The must run designation for the Presque Isle units 5 and 6 should not be eliminated when estimating 2010 fuel costs.

Alternative Two: The must run designation for the Presque Isle units 5 and 6 should be eliminated when estimating 2010 fuel costs.

b. Should test year fuel cost be based on Colorado Coal burn of 1.3 million tons, 1.1 million tons or the level of tons forecasted by the PROMOD model without requiring additional Colorado coal burn?

Background

During the Commission staff audit WEPCO stated that MISO was not dispatching the WEPCO-owned generating units as often as in the past because of the significant reduction in load over the MISO footprint in 2009 and based on the current estimated loads for 2010. WEPCO had contracted for the coal at these units prior to the significant reduction in load for 2009 and 2010 resulting in excessive coal inventory buildup in those years.

Discussion

Commission staff witness James Wagner testified to a $4.0 million increase in 2010 fuel costs to reflect a burn of 1.1 million tons of high BTU bituminous (Colorado) coal. The economic dispatch associated with the generating units that burn Colorado coal does not use all of the coal under contract for 2010 and WEPCO has run out of space to store the coal.
Mr. Wagner testified that WEPCO needed to provide support showing that force burn (uneconomic dispatch) of Colorado coal is the most economic method of alleviating the problem

of excess Colorado coal under contract to keep the additional $4.0 million in final revenue requirement. (Wagner, Tr. D11.23–D11.24)

WEPCO witness Paul Schumacher testified that the 1.1 million tons included in Commission staff's fuel estimate is 200,000 tons short of the amount of Colorado coal under contract for 2010. "The significantly lower demand for power across the MISO footprint during 2009 reduced MISO dispatch and utilization of these units, resulting in lower coal burns than projected." Mr. Schumacher testified the company has sought additional storage of coal and going into 2010 the company will have utilized, to the maximum extent possible, its coal storage capabilities. The company has attempted to sell some of its coal inventory, but has not found buyers due to overall reduced demand. Mr. Schumacher testified that the company has no other option except to burn coal under contract by increasing the utilization of the units by decreasing that price at which the company offers its output in the MISO energy market. The additional 200,000 tons would increase test year fuel costs by approximately $2.3 million. (Schumacher, Tr. R1.70p–R1.71p)

Mr. Schumacher testified that over a six-year history, the 1.3 million tons annually that is under contract corresponded to the likely coal burn at the units. Having sufficient coal at these units allowed the Company to operate the units at optimal levels. Mr. Schumacher testified, "If the Company were forced to reduce generation to maintain coal inventory, replacement energy would have been provided by either gas-fired units or market purchases, or the Company would have had to secure additional coal from the spot market. All of these alternatives would, in most cases, be more costly to customers." (Schumacher, Tr. R1.70p)

CUB in its initial brief states that the Commission should not only disallow the $2.3 million additional amount requested by WEPCO but should also disallow the $4.0 million included in Commission staff's filed fuel estimate. CUB believes that WEPCO has not supported the inclusion of these costs in its test year revenue requirement. (CUB Init. Br. at 11-13)

Alternatives

Alternative One: The 2010 test year fuel cost should be based on a Colorado coal burn of 1.3 million tons.

Alternative Two: The 2010 test year fuel cost should be based on a Colorado coal burn of 1.1 million tons.

Alternative Three: The 2010 test year fuel cost should be based on a Colorado coal burn from the PROMOD model without any uneconomic dispatch.

28. Should the fuel cost estimate for 2010 be adjusted to reflect the energy revenues for the Port Washington units equal to the fuel and variable costs in the PROMOD model?

Background

WEPCO used the PROMOD security-constrained production cost model to project how its generating resources would be utilized in 2010 under MISO dispatch. This model will project the fuel and variable O&M costs of the unit, and the estimated revenues received for the generating source based on Locational Marginal Prices (LMP) calculated by PROMOD. There is no disagreement that, for the Port Washington units, the PROMOD model calculates fuel and variable O&M costs greater than the estimated revenues for the generation based on PROMOD forecasted LMPs and Real-time Make Whole Payments included in the PROMOD run. CUB believes this gap should be eliminated and 2010 monitored fuel costs should be reduced. WEPCO believes this gap is explained by Ancillary Service Market revenues and Make Whole Payments estimated outside of the PROMOD model.

Discussion

CUB witness Mr. Hahn testified that the Port Washington units show fuel and variable O&M expenses that are $19 million above revenues calculated using PROMOD calculated LMPs. Mr. Hahn testified even though WEPCO, in response to Data Request MAR-30-2, attempts to explain this gap based on Make Whole Payments included in the PROMOD run and ASM revenues, he does not believe this response demonstrates that the company's estimate of ASM revenues properly reflects all the benefits the company should expect to receive for the Port Washington units. (Hahn, Tr. D3.62-D3.63) Mr. Hahn testified that test year fuel costs should be reduced by $5.4 million based on the difference between the $19 million and the Make Whole Payments in PROMOD of $13.6 million. (Hahn, Tr. SR3.26)

WEPCO witness Mr. Schumacher testified that the Port Washington units are eligible for Real-time and Day Ahead Make Whole Payments with Real-time payments forecasted by PROMOD and Day Ahead payments based on historical experience. Mr. Schumacher testified the Port Washington units contribute to the ASM and receive ASM revenues. "The sum of Make-Whole Payments and ASM revenues augment the revenues from the energy market to compensate for variable costs associated with unit operation." (Schumacher, Tr. SSR1.17)

The offsetting of ASM revenues against the difference between fuel and variable O&M and projected revenues received based on PROMOD forecasted LMPs may be appropriate if the ASM estimate of $6.5 million is only ASM revenues received and not the net benefit to WEPCO for participating in the ASM.

Mr. Schumacher testified that "MISO launched the ASM on January 6, 2009. As of the date of this filing, the Company has no basis from which to change the assumed level of monitored fuel cost reductions attributed to the ASM by the Commission in the 2008 Final Order. Accordingly, the Company has reduced 2010 monitored fuel costs by about $6.5 million which is about $2.7 million more than the amount included in the 2008 Final Order because the MISO ASM was assumed to be operational for only a partial year during 2008.” (Schumacher, Tr. 97R)

The estimate in the 2008 Final Order was for the net benefit of the ASM on WEPCO’s 2008 fuel costs. Since the ASM test year estimate is already a net number, it would not be appropriate to offset this net estimate against the revenue gap calculated for the Port Washington units. Therefore, it appears test year fuel costs could be reduced by $5.4 million as proposed by CUB witness Mr. Hahn.

Alternatives

Alternative One: Test year fuel costs should not be reduced by $5.4 million associated with the revenue shortfall for the Port Washington units in PROMOD due to anticipated revenues from the ASM.

Alternative Two: Test year fuel costs should be reduced by $5.4 million associated with the revenue shortfall for the Port Washington units in PROMOD because it is not appropriate to offset this revenue shortfall with ASM revenues since the 2010 ASM estimate is already a net benefit estimate.

29. Should test year fuel costs be based on Commission staff’s proposed alternative natural gas cost recovery method?

Background

The Commission staff proposed an alternative natural gas recovery method due to the current low natural gas prices compared to the New York Mercantile Exchange (NYMEX) future prices. Commission staff proposed the alternative natural gas recovery method so as to not collect higher natural gas costs from customers until improved economic conditions for customers has occurred. This alternative is not included in Commission staff's proposed revenue requirement.

Discussion

Commission staff witness Mr. Wagner proposed an alternative natural gas cost recovery method. (Wagner, Tr. D11.25-D11.28) Mr. Schumacher in rebuttal testimony testified to various concerns about this alternative method for the recovery of natural gas cost. (Schumacher, Tr. R1.72p-R1.76p) Mr. Wagner testified that "Commission staff has presented this alternative natural gas recovery in other utility rate proceedings for the 2010 test year. In the Wisconsin Public Service Corporation (WPSC) rate proceeding, WPSC witness Mr. John Guntlisbergen provided testimony revising the Commission staff's proposal with the following changes and clarifications:

> (1) If rates are reduced for the proposed deferred recovery of gas costs, the resulting revenue requirement reduction must be included as a reduction to the fuel monitoring costs, since the reduction is fuel related.
>
> (2) Any deferral of natural gas costs on an actual basis due to actual natural gas prices being higher than natural gas prices allowed in rates must be included as a reduction to actual fuel costs in the fuel variance analysis as well, similar to the treatment of other fuel and purchased power cost deferrals.
>
> (3) Deferrals of natural gas costs would be determined based on forecasted unhedged volumes used in the determination of the revenue requirement reduction. No adjustments should be made for differences in actual and forecasted natural gas volumes used.
>
> (4) The Company would be allowed to defer for future recovery any higher price for natural gas on an actual basis that exceeds the reduced natural gas prices that are included in rates for the natural gas volumes that were unhedged and used in the determination of the revenue requirement reduction for the natural gas pricing. That deferral, however, would be capped at the higher NYMEX futures prices for 2010 that would otherwise been used to establish the Company's 2010 monitored fuel base.
>
> (5) The natural gas cost deferral methodology would need to allow for deferral and recovery of carry cost at the Company's pre-tax weighted average cost of capital on costs deferred for later recovery, in order make the delayed recovery comparable to current recovery in rates.

Commission staff agrees with these changes and clarifications except for the carrying costs to be applied to any outstanding deferred balance. The Commission has generally authorized the deferral of carrying costs based on the approved short-term debt rate for deferrals that are anticipated to be on utility books for only a short time.

Commission staff believes these changes and clarifications would address some of the concerns presented by Mr. Schumacher in his rebuttal testimony. Mr. Schumacher's concerns regarding the perceived additional fuel cost risks for the second year of the biannual period may be addressed by the Commission approving a fuel-only proceeding for 2011 fuel costs to be filed in the second half of 2010." **(**Wagner, Tr. SR11.10-SR11.11))

Mr. Schumacher in sur-surrebuttal raised three concerns associated with the Commission staff alternative proposal which are: (1) The impact of the proposal on a utility which is a net seller of energy to the MISO energy market; (2) How key inputs to the method for establishing gas cost deferral is memorialized for future recovery; and (3) How deferred amounts be treated under a fuel cost proceeding. (Schumacher, Tr. SSR1.13)

The first concern raised by Mr. Schumacher will not be addressed by the Commission staff alternative proposal because the change in gas cost is made after PROMOD is run using the NYMEX futures prices. The second concern would be addressed by a specific appendix in the Final Order showing the dekatherms by month for which any change in natural gas prices would be applied. The third concern based on the WPSC changes and clarification would move the deferred amount out of fuel costs to a deferred account which could be recovered in a fuel proceeding or base rate case. (Wagner, Tr. 327-328, 331-332)

WEPCO is not sure that the alternative natural gas cost recovery method revised to reflect changes and clarifications proposed by Mr. Guntlisbergen in the WPSC rate proceeding addresses the concerns raised by Mr. Schumacher in rebuttal testimony. WEPCO believes this alternative proposal raises a legal issue. WEPCO believes this alternative resembles changes to the fuel rules in docket 1-AC-224 that were opposed by CUB and others as retroactive ratemaking. Therefore, any deferred fuel cost on the company's balance sheet could be at risk. (WEPCO Init. Br. at 25-26)

Alternatives

Alternative One: The Commission does not approve the Commission staff's proposed alternative gas recovery method.

Alternative Two: The Commission approves the Commission staff's proposed alternative gas recovery method and WEPCO shall record interest on the outstanding balance using ___ percent for carrying costs.

30. Should test year fuel costs be reduced by $1.5 million to reflect potential insurance recoveries for environmental clean-up costs?

Discussion

Commission staff witness Mr. Wagner testified that test year fuel and ash handling costs should be reduced by $1.5 million to reflect the potential for insurance recoveries for environmental clean-up costs. (Wagner, Tr. D11.24) Mr. Wagner testified that "The recovery of environmental clean-up costs from insurance companies is difficult to forecast because the actual recoveries are negotiated with the insurance companies. This is evidenced by the $3.5 million insurance recovery received in 2008 that was not forecasted for the 2008 test year. The insurance premiums associated with the recoveries are included as a cost recoverable from ratepayers. Therefore, Mr. Wagner believes it is appropriate to attempt to forecast some insurance recoveries for the benefit of the ratepayers of WEPCO." (Wagner, Tr. SR11.11)

Mr. Schumacher testified that there is no planned recovery of any environmental clean-up costs and the only remaining insurance carrier for ash sites is essentially in bankruptcy.

Mr. Schumacher testified that because of the unpredictable nature of insurance recovery, he proposed that should the company receive any proceeds from an insurance claim on this matter, the proceeds will be returned to customers in a future proceeding. (Schumacher, Tr. R1.77p, SSR1.14)

Alternatives

Alternative One: The 2010 test year Fuel and Ash Handling costs should not be reduced by $1.5 million for any potential insurance recoveries and any insurance proceeds received for an insurance claim concerning environmental clean-up costs will be deferred to a future rate case.

Alternative Two: The 2010 test year Fuel and Ash Handling costs should be reduced by $1.5 million for any potential insurance recoveries for environmental clean-up costs.

31. Should the Commission approve WEPCO's request for a limited fuel reopening for 2011 fuel costs?

Alternative One: WEPCO is approved to file for a limited fuel reopening to review 2011 fuel costs.

Alternative Two: WEPCO is not authorized to file for a limited fuel reopening for 2011 fuel costs.

32. Should WEPCO's annual fuel monitoring range be changed from plus or minus 2 percent to plus or minus 1 percent?

Alternative One: The annual fuel monitoring range should be changed from plus or minus 2 percent to plus or minus 1 percent.

Alternative Two: The annual fuel monitoring range should remain at plus or minus 2 percent.

33. Should the test year fuel costs be updated to reflect the most recently available mid-month NYMEX future prices for natural gas, heating oil and crude oil prices? (Uncontested)

34. Should the peak load used in the PROMOD model be the same peak load used by WEPCO in its Reserve after Scheduled Maintenance (RASM) analysis?

Alternative One: Peak load in PROMOD should not be net of interruptible load.

Alternative Two: Peak load in PROMOD should be net of interruptible load the same as the RASM analysis.

FINANCIAL ISSUES

35. What is an appropriate Capital Structure?

Background

Commission staff presented two capital structures in its testimony. Each serves a different purpose; one is the financial capital structure and the other the regulatory, or ratemaking, capital structure.

The financial capital structure is intended to reflect the company's capitalization giving consideration to the company's total assets, including those not allowed in rate base, and debt attribution relating to off-balance sheet obligations. The Commission's long-term equity ranges for WEPCO and WG are set on the basis of the company's financial capital structure. The financial capital structure is ordinarily the one used to determine credit ratings. Commission staff generally looks to the financial markets when developing options regarding the appropriate equity levels for WEPCO and WG.

The weighted cost of capital used for ratemaking is calculated on the regulatory capital structure. The regulatory capital structure is also based on booked capitalization with adjustments determined by the Commission. For example, the Commission in dockets 6650-GR-6 and 6630-UR-111 determined that non-utility investments should be excluded from the regulatory capital structure for WG and WEPCO, respectively.

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The following tables show Commission staff's test year estimates of WEPCO's and WG's financial and regulatory capital structures as shown on Schedule 1 of Exhibit 11.3:

Wisconsin Electric Power Company			
	Financial		Regulatory
Common Stock Equity	$ 2,942,893,000		$ 2,942,893,000
Non-utility Investments and other			(17,422,000)
ATC Investment			(226,140,000)
Common Stock Equity	$ 2,942,893,000		$ 2,699,331,000
Preferred Stock	30,450,000		30,450,000
Long-term Debt	$ 2,149,350,000		$ 2,149,350,000
Short-term Debt	212,387,000		212,387,000
Power the Future Lease	0		
Purchased Power Capital Leases and Non-Purchased Power Operating Leases	163,442,000	(a)	
Purchased Power Agreements	272,002,000	(b)	
Wind Related Land Leases and PPAs	0	(c)	
Guarantees	0	(d)	
Debt of Subsidiary	0	(e)	
Underfunded Pension and OPEB, and ARO	0	(f)	
Adjusted Debt	$ 2,797,181,000		$ 2,361,737,000
Total Capitalization	$5,770,524,000		$5,091,518,000
Equity in Capital Structure	51.00%		53.02%

a. This item is subject to sub-issues e and g.
b. This item is subject to sub-issues e and h.
c. This item is subject to sub-issues e, i, and j.
d. This item is subject to sub-issues e and k.
e. This item is subject to sub-issues e and l.
f. This item is subject to sub-issues e and m.

Wisconsin Gas, LLC			
	Financial		Regulatory
Common Stock Equity	$ 548,180,000		$ 548,180,000
Goodwill	(95,889,000)		(95,889,000)
Other pushed-down adjustments	(76,561,000)		(76,561,000)
Non-utility Investments and other			(12,973,000)
Common Stock Equity	$ 375,731,000	(a)	$ 362,757,000
Preferred Stock	0		0
Long-term Debt	$ 260,000,000		$ 260,000,000
Short-term Debt	155,295,000		155,295,000
Off Balance Sheet Adj.	0		
Adjusted Debt	$ 415,295,000		$ 415,295,000
Total Capitalization	$ 791,026,000		$ 778,052,000
Equity in Capital Structure	47.50%		46.62%

a. Rounding

a. What is a reasonable long-term range for common equity in WEPCO's financial capital structure? (Uncontested)

b. What is a reasonable long-term range for common equity in WG's financial capital structure? (Uncontested)

c. What is the appropriate common equity ratio target for WEPCO's financial equity?

Background

The applicants' witness, Ms. Wolter, used a financial capital structure with 50.99 percent common equity and proposed a level of 51.0 percent for the test year. (Wolter, Tr. 144, Ex. 21) WIEG's witness, Mr. Kollen, proposed a target at the lower end of the approved common equity range. (Kollen, Tr. D2.46-D2.47) Commission staff used a common equity target, on a financial basis, of 51.0 percent. (Hubert, Tr. D11.52, Ex. 11.3, Sch. 1, p. 1)

Discussion

In its January 17, 2008, *Final Decision* in docket 5-UR-103, the Commission found "An appropriate target level for WEPCO's test year average common equity measured on a financial basis is 51.0 percent." Both the applicant's witness and the Commission staff witness used 51.0 percent. WIEG's witness, Mr. Kollen, argued that there is no need to set the target in the center of the range and recommended a target at the lower end of the range be used. (Kollen, Tr. D2.47) While no target level was specified for the financial capital structure, the impact on the regulatory capital structure would indicate a reduction of approximately 0.60 percent to 50.4 percent on a financial basis.

Alternative One reflects Mr. Kollen's position. Alternative Two reflects the target approved in docket 5-UR-103, while Alternative Three reflects the fact that the Commission is not bound to the alternatives proposed by the parties.

Alternative One: An appropriate target level for WEPCO's test year average common equity measured on a financial basis is ___ percent, and is at the lower end of WEPCO's approved equity range.

Alternative Two: An appropriate target level for WEPCO's test year average common equity measured on a financial basis continues to be 51.0 percent.

Alternative Three: An appropriate target level for WEPCO's test year average common equity measured on a financial basis is ___ percent. (An amount within WEPCO's approved equity range.)

d. What is the appropriate common equity ratio target for WG's financial equity? (Uncontested)

e. What is the appropriate treatment for imputation of off-balance sheet debt obligations?

Background

This Commission has a history of recognizing off-balance sheet debt obligations. (December 23, 1985, *Findings of Fact and Order* in docket 6630-ER-100, *Application of Wisconsin Electric Power Company, for Authority to Increase Retail Electric Rates with Respect to 1986 Test Year*) In its September 13, 2002, *Final Decision* in docket 6680-UR-111 the Commission found "It is reasonable that the financial capital structure to be used in Commission proceedings should include WP&L's off-balance sheet obligations, including the debt equivalent of accounts receivables sales, purchased power and operating leases." In subsequent proceedings, the Commission has required the utilities to file information supporting the amount of off-balance sheet obligation to be included. (Hubert, Tr. D11.50-D11.51) In this and other rate proceedings before the Commission this year, the Commission is being asked to reconsider its position on the issue.

Discussion

The Commission has a spectrum of choices to make regarding the imputation of debt equivalence. On the one end is the acceptance of all debt equivalents calculated by S&P or another rating agency and the other end is the discontinuance of imputing any debt equivalents.

The applicants' position is summarized in its brief as the Commission should continue to deal with off-balance sheet debt obligations as it has dealt with them in the past. (WEPCO Init. Br. at 32) The applicants' position is that while there is a cost to maintain the capital structure the alternative would be credit downgrading. Alternative One reflects the applicants' position. The applicants also argue that the "pay twice" argument mischaracterizes the situation; the Commission should not assume that just because Standard and Poor's (S&P) publishes a rigorous formula and Moody's and Fitch do not that Moody's and Fitch are not just as concerned about the issue; and that abandoning its approach amounts to a de facto increase in the company's financial leverage. (WEPCO Reply Br. at 3)

Alternative Two reflects CUB's position. CUB recommends reducing WEPCO's revenue requirement by $26.6 million by eliminating the equity infusion associated with the off-balances-sheet debt obligations. (CUB Init. Br. at 5P) CUB argues that ratepayers pay twice. First they pay for the direct cost of these obligations in the cost of service and again in the form of a return on the equity that has been added to offset the present value of what is, effectively, a hypothetical debt obligation. (CUB Init. Br. at 6P) It briefs that the cure is more expensive than the problem it is designed to address. CUB further argues that the process affords too much weight and mathematical precision to this one small portion of the bond rating process and affords far too much weight to one rating agency. (CUB Init. Br. at 7P) CUB argues that even if a downgrading occurs, the bond rating reduction would be considerably less costly to ratepayers than the Commission's ratemaking treatment of the off-balance-sheet obligations. (CUB Init.

Br. at 7P) CUB notes that the vast majority of state commissions do not see the need to require ratepayers to pay twice by imputing debt for off-balance-sheet obligations. (CUB Init. Br. at 6P) In addition, the practice has never been as straight forward or consistent as the applicants imply making it easily to be subject to abuse and difficult to tell what effect, if any, the rating agencies' consideration of debt imputation actually has on each of the company's credit ratings. (CUB Reply Br. at 9)

Alternative Three reflects Commission staff's filing. This is the second year in which the question of appropriate treatment of debt imputation was raised by Commission staff's witness, Ms. Hubert. Ms. Hubert testified that to impute debt and thus incur additional cost to ratepayers for presumed risk that the Commission does not believe exists or should not be the responsibility of ratepayers is not in the public interest and she believed the Commission must determine which debt obligations contain risks that the ratepayers should compensate stockholders for and to only impute that debt. (Hubert, Tr. SR11.15) The argument commonly given for debt imputation treatment is to defer the amount and methodology to the rating agencies and utilities. However, such treatment has lead to inconsistency in utility positions raising concerns about incentives. (Hubert, Tr. D11.42)

Sub-issues f through m relate to the various types of off-balance sheet debt obligations reviewed in this docket. If the Commission selects Alternative Two, the amount of debt to be imputed under each of the sub-issues would be zero. Sub-issues g and h are shown as uncontested as both WEPCO and Commission staff agree on the amount based on methodologies used in past proceedings. However, the inclusions of the amounts remain subject to elimination under this sub-issue.

Sub-issue m is also shown as uncontested. It is in other proceedings that the argument has been made to include debt equivalence for underfunded pension and other post-retirement employee benefit plans and asset retirement obligations. While the Commission could determine that debt imputation of up to $433,061,000 be included, such determination is not expected since neither WEPCO, CUB nor Commission staff supports inclusion. Consequently, it is treated as an uncontested issue with no debt equivalent added to the financial capital structure.

Alternative One: It is reasonable for the Commission to continue to deal with off-balance sheet obligations as it has dealt with them in the past.

Alternative Two: It is reasonable for the Commission to discontinue imputing debt equivalents for off-balance sheet debt obligations.

Alternative Three: It is reasonable for the Commission to determine what and how much debt imputation to include in the financial capital structure based on its assessment and allocation of any associated risk not based on the assessment of any rating agency.

f. What is the debt equivalent of WEPCO's off-balance sheet obligations relating to the Power the Future Capital Leases? (Uncontested)

g. What is the debt equivalent of WEPCO's off-balance sheet obligations relating to its Purchased Power Capital Leases and Non-Purchased Power Operating Leases for the test year? (Uncontested)

h. What is the debt equivalent of WEPCO's off-balance sheet obligations relating to Purchased Power Agreements? (Uncontested)

i. What is the debt equivalent of WEPCO's off-balance sheet obligations for its wind-related purchased power agreements?

Background

WEPCO included $1,274,702 of debt equivalent relating to a new wind-related purchased power agreements in its financial capital structure. (Hubert, Tr. D11.36) Commission staff did not include any debt imputation in Commission staff's financial capital structure. (Hubert, Tr. D11.35-11.36, Ex. 11.3, Sch. 1, pp. 1 and 5) CUB recommends that the Commission discontinue imputation of debt relating to off-balance sheet obligations. (CUB Init. Br. at 5P)

Discussion

Commission staff witness Ms. Hubert calculated $837,695 for the Montfort Wind Farm purchased power agreement and $845,207 for the new proposed wind farm purchased power agreement but did not include it in the test year financial capital structure. WEPCO had calculated $1,275,000 for an unnamed proposed wind farm purchased power agreement but nothing for the Montfort Wind Farm purchased power agreement.

Ms. Hubert expressed reservations to imputing any amount noting that the payments were for energy not capacity and to meet an energy requirement not capacity requirement. Furthermore, wind in particular has a very low capacity factor and cannot be dispatched at the needs of the customer. She questioned whether there was any risk transfer from the project owner to the utility. Lastly, she recommended that the Commission use a 25 percent risk factor if it imputed debt and questioned the inclusion of the new purchased power agreement as it is not yet signed. (Hubert, Tr. D11.40-D11.44)

Alternative One reflects the maximum amount calculated by Commission staff.

Alternative Two reflects the discontinuance of the practice of imputing debt. It can also reflect a Commission decision to not impute debt for this category of off-balance sheet debt obligation.

Alternative Three recognizes that the Commission is not limited to the amounts proposed by the various parties.

Alternative One: A reasonable estimate of the debt equivalent of WEPCO's off-balance sheet obligations for its wind-related purchased power agreements, to be imputed into the financial capital structure for the test year is $1,684,000.

Alternative Two: No debt equivalent for WEPCO's off-balance sheet obligations for its wind-related purchased power agreements is imputed into the financial capital structure for the test year.

Alternative Three: A reasonable estimate of the debt equivalent of WEPCO's off-balance sheet obligations for its wind-related purchased power agreements, to be imputed into the financial capital structure for the test year is $____________. (An amount between zero and $1,684,000.)

j. What is the debt equivalent of WEPCO's off-balance sheet obligations for its Wind-Related Land Leases?

Background

WEPCO did not include any debt equivalent relating to wind-related land leases. (Hubert, Tr. D11.47) Commission staff did not include any debt imputation in Commission staff's financial capital structure. (Ex. 11.3, Sch. 1, pp. 1 and 5) CUB recommends that the Commission discontinue imputation of debt relating to off-balance sheet obligations. (CUB Init. Br. at 5P)

Discussion

Commission staff witness, Ms. Hubert, calculated $7,286,568 of debt equivalent for landowner leases associated with the Blue Sky Green Field and Byron wind farms but did not include any amount in the test year financial capital structure. As with sub-issue i, questions have arisen regarding the treatment of costs associated with renewable energy including wind energy. (Hubert, Tr. D11.37) Ms. Hubert did not include any costs for the Glacier Hills Wind Park which is still in the authorization phase and has an in-service date of December 31, 2011, or for non-base payments associated with the Byron wind farm. WEPCO had not included any debt equivalences for landowner leases. (Hubert, Tr. D11.47)

Ms. Hubert identified three options for the Commission: (1) Determine that a debt imputation should not be included for wind farm/RPS-related land leases; (2) Determine that debt imputation should be included for wind farm/RPS-related land leases based on the contracted payments assuming continued operations; or (3) Determine that debt imputation should be included for wind farm/RPS payments but the imputation should be on the lesser cost of continued operation or discontinuation of operation. The third option had been raised by Wisconsin Power and Light Company in docket 6680-U-117 and if selected would result in a imputation of zero for WEPCO. (Hubert, Tr. D11.48) The Commission also has CUB's proposal to discontinue imputing debt for any off-balance sheet debt obligation.

Alternative One reflects the maximum amount calculated by Commission staff.

Alternative Two reflects the discontinuance of the practice of imputing debt. It can also reflect a Commission decision to not impute debt for this category of off-balance sheet debt obligation or that debt imputation should be included for wind farm/RPS payments but the imputation should be on the lesser cost of continued operation or discontinuation of operation.

Alternative Three recognizes that the Commission is not limited to the amounts proposed by the various parties.

Alternative One: A reasonable estimate of the debt equivalent of WEPCO's off-balance sheet obligations for its wind-related land leases, to be imputed into the financial capital structure for the test year is $7,287,000.

Alternative Two: No debt equivalent for WEPCO's off-balance sheet obligations for its wind-related land leases is imputed into the financial capital structure for the test year.

Alternative Three: A reasonable estimate of the debt equivalent of WEPCO's off-balance sheet obligations for its wind-related land leases, to be imputed into the financial capital structure for the test year is $___________. (An amount between zero and $7,287,000.)

k. What is the debt equivalent of WEPCO's off-balance sheet obligations relating to Guarantees?

Background

WEPCO did not include any debt equivalent relating to guarantees. Commission staff did not include any debt imputation in Commission staff's financial capital structure. (Ex. 11.3, Sch. 1, p. 1) CUB recommends that the Commission discontinue imputation of debt relating to off-balance sheet obligations. (CUB Init. Br. at 5P)

Discussion

Commission staff witness, Ms. Hubert, calculated less than $87,000 of customer loan guarantees associated with WEPCO's Dairy Farm Loan Program. She excluded the amount from the financial capital structure due to its relative immateriality and the fact that WEPCO did not include it. (Hubert, Tr. D11.47) In rebuttal testimony, WEPCO's witness, Ms. Wolter stipulated to the amounts calculated by Ms. Hubert for these particular items. (Wolter, Tr. R1.60) Such stipulation raises questions as to whether WEPCO now wishes consideration of this minimal amount.

Alternative One reflects the maximum amount.

Alternative Two reflects the discontinuance of the practice of imputing debt. It can also reflect a Commission decision to not impute debt for this category of off-balance sheet debt obligation or that debt imputation is immaterial for the test year.

Alternative Three recognizes that the Commission is not limited to the amounts proposed by the various parties.

Alternative One: A reasonable estimate of the debt equivalent of WEPCO's off-balance sheet obligations relating to its guarantees, to be imputed into the financial capital structure for the test year is $87,000.

Alternative Two: No debt equivalent for WEPCO's off-balance sheet obligations relating to its guarantees is imputed into the financial capital structure for the test year.

Alternative Three: A reasonable estimate of the debt equivalent of WEPCO's off-balance sheet obligations relating to its guarantees, to be imputed into the financial capital structure for the test year is $___________. (An amount between zero and $87,000.)

l. What is the debt equivalent of WEPCO's off-balance sheet obligations relating to debt of its Subsidiary?

Background

WEPCO did not include any debt equivalent relating to debt of its Subsidiary. Commission staff did not include any debt imputation in Commission staff's financial capital structure. (Ex. 11.3, Sch. 1, p. 1) CUB recommends that the Commission discontinue imputation of debt relating to off-balance sheet obligations. (CUB Init. Br. at 5P)

Discussion

Commission staff witness, Ms. Hubert, identified $29,600,000 of debt associated with a WEPCO subsidiary. She excluded the amount from the financial capital structure because she assumed the note was temporary and would not be renewed for the test year. She testified that the loan is not associated with a regulated utility business. (Hubert, Tr. D11.49) This latter point raises questions as to the reasonableness of ratepayers bearing the cost of credit restoration for the debt. In rebuttal testimony, WEPCO's witness, Ms. Wolter stipulated to the amounts calculated by Ms. Hubert for these particular items. (Wolter, Tr. R1.60) Such stipulation raises questions as to whether WEPCO now wishes consideration of this amount.

Alternative One reflects the maximum amount.

Alternative Two reflects the discontinuance of the practice of imputing debt. It can also reflect a Commission decision to not impute debt for this category of off-balance sheet debt obligation or that debt is presumed to be temporary and will not be in existence for the test year.

Alternative Three recognizes that the Commission is not limited to the amounts proposed by the various parties.

Alternative One: A reasonable estimate of the debt equivalent of WEPCO's off-balance sheet obligations relating to the debt of its subsidiary to be imputed into the financial capital structure for the test year is $29,600,000.

Alternative Two: No debt equivalent for WEPCO's off-balance sheet obligations relating to the debt of its subsidiary is imputed into the financial capital structure for the test year.

Alternative Three: A reasonable estimate of the debt equivalent of WEPCO's off-balance sheet obligations relating to the debt of its subsidiary, to be imputed into the financial capital structure for the test year is $___________. (An amount between zero and $29,600,000.)

m. What is the debt equivalent of WEPCO's off-balance sheet obligations relating to underfunded pension and other post-retirement employee benefit plans and asset retirement obligation? (Uncontested)

n. Should WEPCO file detailed off-balance sheet obligation data in its next rate application? (Uncontested)

o. What is a reasonable financial capital structure for WEPCO in this docket? (Uncontested)

p. What is a reasonable financial capital structure for WG in this docket? (Uncontested)

q. What is a reasonable capital structure for ratemaking for WEPCO in this docket? (Uncontested)

r. What is a reasonable capital structure for ratemaking for WG in this docket? (Uncontested)

s. What is the appropriate wording for WEPCO's dividend restriction? (Uncontested)

t. What is the appropriate wording for WG's dividend restriction? (Uncontested)

u. Should WEPCO and WG file ten-year financial forecasts in their next rate applications? (Uncontested)

36. What is an appropriate Cost of Capital?

a. What is a reasonable return on equity for WEPCO and WG for the test year?

Background

The company's witness, Ms. Wolter, requested an authorized return on common equity of 10.75 percent (Wolter, Tr. 136) with a range of 9.3 to 13.3 percent for WEPCO and a range of 9.6 to 14.3 percent for WG. (Wolter, Tr. 183) CUB supports a return on equity of 10.0 percent. (CUB Init. Br. at 3P) Commission staff's witness, Ms. Hubert, testified that a reasonable range was 10.0 percent to 10.75 percent and instructed Commission staff to use 10.75 percent for the test year revenue requirement calculation. (Hubert, Tr. D11.31) Updated Commission staff models will be provided at the time of the discussion of the record to assist the Commission in making a final determination. (Hubert, Tr. 11.66)

Discussion

CUB's witness, Mr. Hill, did not perform a cost of capital analysis in this proceeding. However, his most recent analyses performed in early 2009 indicated a reasonable range of 9.25 percent to 10.0 percent. (Hill, Tr. D3.24) CUB argues that the Commission must consider the inability of many customers to pay any increase; in the past, under similar circumstances has determined that a utility's return should be reduced; and reducing the return is appropriate because one of the main drivers of the request is a decline in electric consumption. (CUB Br. 13P-15P)

Both applicants' witness, Ms. Wolter, and Commission staff's witness, Ms. Hubert used 10.75 percent return on equity in their test year capital structure. However, Ms. Hubert testified that she did not concur with Ms. Wolter's analysis. (Hubert, Tr. 11.67) There are substantial differences in the positions of the two witnesses which the Commission should consider before assuming that "the applicant's proposed return on equity . . . has not been contested." (WEPCO Init. Br. at 26).

Ms. Wolter's range of return for WEPCO was 9.3 percent to 13.3 percent with a midpoint estimate of 11.3 percent and range of return for WG was 9.6 percent to 14.3 percent with a midpoint of 11.9 percent. (WEPCO Init. Br. at 26) Ms. Hubert's range was 10.0 percent to 10.75 percent. (Hubert, Tr. D11.31) Consequently, Ms. Wolter believes that the 10.75 percent is well within the range, and Ms. Hubert argues that she took a cautionary position, but the data would support the Commission authorizing a return lower than that used by her. (Hubert, Tr. D11.65)

In briefs, the applicant characterizes Ms. Hubert's disagreement with Ms. Wolter as "technical disagreements" (WEPCO Init. Br. at 29) and Ms. Wolter's models as "traditional analytic techniques." (WEPCO Init. Br. at 26) However, Ms. Hubert testified that while characterized as traditional, some of the variants of the models used by Ms. Wolter were not traditional and have in fact been rejected by this Commission and/or other state regulatory commissions. (Hubert, Tr. D11.67-D11.97)

The applicant also provided a witness to give a utility credit rating perspective. Ms. Abbott focused on the difficult credit market, the company's credit metrics and the importance of the Commission not reducing the company's allowed return on equity. (WEPCO Init. Br. at 28) Ms. Hubert testified that the utility sector has continued to have access to the capital market, WEPCO and WG are well position relative to other companies for competing for financing, and Commission support also comes from policies unrelated to the return on equity. (Hubert, Tr. D11.96-D11.100) In addition Ms. Hubert testified that two factors are important to the utility's credit rating: regulation and the utility's management. Wisconsin Energy's actions could be considered not credit supportive. (Hubert, D 11.97-D11.98, SR11.12-SR11.14) CUB argues that the company needs to stop looking to its ratepayers to shore up its credit rating with unnecessarily high returns and instead rely on its management and that of its parent to take more supportive actions to maintain WEPCO's credit. (CUB Reply Br. at 7)

Lastly, the applicant provided a witness to give an economist's perspective. Dr. Stelzer cautioned the Commission on erring too low on the return on equity decision. (WEPCO Init. Br. at 29) CUB briefs that Dr. Stelzer (as well as Ms. Abbott) failed to take into consideration the impact a 10.75 percent return will have on ratepayers and that there is an ever-growing chasm between the theory WEPCO's witnesses rely on to support WEPCO's request and the practical reality of the lives of the people who will have to pay for this profit. (CUB Reply Br. at 5-6)

WEPCO began its Brief with the following:

> Traditional regulatory principles define just and reasonable rates as those which provide a utility with a meaningful opportunity to recover all of the costs it prudently incurs to provide service to customers, including the cost of capital.

This concept is not lost on the financial community, particularly in today's economy where, due to large sudden sales declines, many companies do not have an opportunity to recover all prudent costs. Companies without regulatory protection are susceptible to greater non-diversifiable business risk, and conversely, companies with regulatory protection less non-diversifiable business risk. The market models reflect the risks that impact the cost of equity. (Hubert, Tr. D11.68) Ms. Hubert testified that the balancing of investor and customer needs is heightened in this economic period. In good economic times, if rates have not been increasing substantially, it is easier to allow the utilities a return greater than required, because customers in general are sharing in the good economy. (Hubert, Tr. D11.64) In bad economic times, it may not be appropriate to allow utilities a return greater than required. Ms. Hubert testified that her 10.75 percent was based on a cautionary perspective and that the principal of gradualism would support a lower return. She based her estimates on financial information available in July. Commission staff will provide updated financial information in Exhibit 11.10.

Alternative One proposes that the Commission set reasonable rates of return on WEPCO's and WG's common stock based on updated data in Commission staff's delayed exhibit.

Alternative Two proposes that the Commission set the reasonable rates of return on WEPCO's and WG's common stock at 10.75 percent, based on the test year filings.

Alternative Three proposes that the Commission set the reasonable rates of return on WEPCO's and WG's common stock at 10.00 percent, in recognition of the impact the current recession is having on WEPCO's ratepayers.

Alternative Four proposes that the Commission set reasonable rates of return based on Commission staff's proposed range for the return on equity.

Alternative One: A reasonable rate of return on WEPCO's and WG's common equity is a percentage based on Exhibit 11.10.

Alternative Two: A reasonable rate of return on WEPCO's and WG's common equity is 10.75 percent.

Alternative Three: A reasonable rate of return on WEPCO's and WG's common equity is 10.00 percent.

Alternative Four: A reasonable range for the rate of return on WEPCO's and WG's common equity is a percentage within the range of 10.0 percent to 10.75 percent.

b. What is a reasonable interest rate for WEPCO's and WG's short-term borrowing through commercial paper?

Background

Applicant's filing included a short-term debt interest rate of 3.20 percent. (Ex. 20, Sch. 1, p. 3 and Ex. 21, Sch. 1, p. 3) WIEG's witness, Mr. Kollen, recommended an interest rate of 1.00 percent and an adder of 1.00 percent to reimburse WEC for the cost of the credit facility allocated to WEPCO. (Kollen, Tr. D2.44) Commission staff's witness, Ms. Hubert, used 1.50 percent, noting that the Commission could continue to use an A-1/P-1 rated commercial paper rate or use an A-2/P-2 rated commercial paper rate. (Hubert, Tr. D11.56)

Discussion

The Commission must set an interest rate for short-term commercial paper for 2010. Three components are involved: (1) Should the Commission continue to use the A-1/P-1 interest rate forecasted in the Blue Chip Financial Forecast; (2) What spread is appropriate if the A-2/P-2 rated commercial paper rate is used; and (3) What, if any, adder should be included for costs associated with credit facilities and should the adder, if applicable, be included as an increased interest rate or as a fixed O&M expense.

Component one relates to the interest rate forecast. Commission practice has been to use the *Blue Chip Financial Forecast* for establishing the short-term debt cost which the Commission has found to be "a reasonable and objective method of determining short-term debt costs" in its January 17, 2008, *Final Decision* in docket 05-UR-103. Use of the *Blue Chip Financial Forecast* is uncontested (WEPCO Init. Br. at 23) and updated estimates will be provided.

Component two relates to whether the Commission wishes to estimate and add a spread between A-1/P-1 and A-2/P-2 rates. Commission's practice has not changed even after the applicants' S&P commercial paper rating changed in 2003 to A-2 from A-1. The applicant's Moody's commercial paper rating remains at P-1. Commission staff documented the recent disruption in the commercial paper market and estimated a spread adder. While Commission staff used an A-2/P-2 commercial paper rate in its test year, Commission staff left the final determination to the Commission as to which rate to use. An update of the estimated adder will be provided in Ex. 11.10. (Hubert, D11.55-D11.56, Ex. 11.3, Sch. 6, p. 2, Ex. 11.10) The applicant supports use of an A-2/P-2 commercial paper rate. (WEPCO Init. Br. at 23)

WIEG's witness, Mr. Kollen, recommended a 1.0 percent adder for allocation of costs associated with WEC's credit facility. (Kollen, Tr. D2.44) In response, applicant's witness, Ms. Wolter, testified that WEPCO and WG operate their own programs but such adder was reasonable to recover those costs. (Wolter, Tr. R1.62) Based on Commission staff's test year, the 1.00 percent adder has a revenue impact of $2,123,870 ($212,387,000 x 0.01) for WEPCO and $1,552,950 ($155,295,000 x 0.01) for WG. Commission staff witness, Ms. Hubert, testified that Ms. Wolter indicated in a data response that in 2008 the costs were $437,210.09 and that this translated into only a 20.6 basis point adder, not 100 basis points. Furthermore, such fees are not tied to the amount of commercial paper outstanding so recovery as an O&M expense may be more appropriate. Lastly, Commission staff was still reviewing the issue at that time. (Hubert, Tr. SR11.23-11.24) After nearly 20 years of using the *Blue Chip Financial Forecast* estimates for short-term borrowing costs (January 3, 1991, *Findings of Fact, Conclusion of Law and Order* in docket 6630-UR-104, *Application of Wisconsin Electric Power Company for Authority to Increase Retail Electric and Steam Rates*), the applicant has determined in rebuttal testimony that an adder is now needed.

Alternative One is an all-inclusive interest rate for commercial paper based on the most recent *Blue Chip Financial Forecast*, any applicable spread relating to ratings, and an adder, if applicable, associated with credit facility costs.

Alternative Two is an all-inclusive interest rate for commercial paper based on the most recent *Blue Chip Financial Forecast* and any applicable spread relating to ratings, with a dollar determined O&M expense associated with any applicable credit facility costs

Alternative One: A reasonable rate for WEPCO's and WG's short-term borrowing through commercial paper is ____ percent, with no additional operating expense being included in O&M expenses.

Alternative Two: A reasonable rate for WEPCO's and WG's short-term borrowing through commercial paper is ____ percent, with $_____of additional operating expense being included in O&M expenses for WEPCO and $_____ of additional operating expense being included in O&M expenses for WG.

c. What is a reasonable interest rate for WEPCO's $250,000,000 long-term debt issuance in 2009?

Background

WEPCO's test year capital structure contained a proposed 2009 debt issuance of $250,000,000 with a forecasted interest rate of 7.0 percent. (Hubert, D11.57) WIEG's witness, Mr. Kollen, proposed an interest rate of 5.80 percent. (Kollen, D2.45) Commission staff's witness, Ms. Hubert used an estimated rate of 6.10 percent for the new issuance based on information available in July 2009. (Hubert, Tr. D11.57-D11.58, Ex. 11.3, Sch. 6)

Discussion

The proposed $250,000,000 was forecasted to be issued in September 2009. The Commission may wish to use the actual issuance rate, if known at the time of its discussion of record. (Hubert, Tr. D11.58) Delayed Exhibit 11.10, to be filed by Commission staff one week before the Commission decision, will provide a current long-term debt rate forecast.

Alternative One recognizes the position of WIEG's witness, Mr. Kollen. Mr. Kollen testified that WEPCO's interest rates were overstated (Kollen, Tr. D2.45) and proposed that the rate should be 5.80 percent. (Ex. 2.11)

Alternative Two establishes the interest rate on the basis of actual, if known, or based on updated forecasts contained in Exhibit 11.10.

Alternative One: A reasonable rate for WEPCO's $250,000,000 long-term debt issuance, if debt issuance is needed, is 5.80 percent.

Alternative Two: A reasonable rate for WEPCO's $250,000,000 long-term debt issuance, if debt issuance is needed, is the actual rate, if known, or a percentage based on Exhibit 11.10.

d. What is a reasonable interest rate for WEPCO's variable-rate long-term debt?

Background

WEPCO's capital structure contained four series of variable-rate long-term debt with two series totaling $17,350,000 having a test year WEPCO-forecasted interest rate of 3.85 percent and two series totaling $147,000,000 having a test year WEPCO-forecasted interest rate of 2.00 percent. (Ex. 2.11) WIEG's witness, Mr. Kollen used interest rates of 1.925 percent and 1.00 percent. (Kollen, Tr. D2.45, Ex. 2.11) Commission staff's witness, Ms. Hubert used an aggregated estimated rate of 1.00 percent based on information available in July 2009. (Hubert, Tr. D11.57, Ex. 11.3, Sch. 6)

Discussion

Alternative One recognizes the position of WIEG's witness, Mr. Kollen. Mr. Kollen testified that WEPCO's interest rates were overstated (Kollen, Tr. D2.45) and proposed that the rates should be 1.925 percent for the two series totaling $17,350,000 and 1.000 percent for the two series totaling $147,000,000. (Ex. 2.11)

Alternative Two recognizes Commission staff's position that the interest rates be based on Exhibit 11.10 which will be filed prior to the Commission's decision in this docket. (D11.57-D11.58) Commission staff used one rate (1.00 percent) for the four tax-exempt series based on 65 percent of the commercial paper rate. Two estimates are included on Schedule 6 based on A-1/P-1 rated commercial paper rates and on A-2/P-2 rated commercial paper rates.

Alternative One: A reasonable rate for WEPCO's variable-rate long-term debt issuance is 1.925 percent for $17,350,000 and 1.00 percent for $147,000,000.

Alternative Two: A reasonable rate for WEPCO's variable-rate long-term debt issuance is a percentage based on Exhibit 11.10.

e. What is a reasonable embedded cost for WEPCO's long-term debt? (Uncontested)

f. What is a reasonable embedded cost for WG's long-term debt? (Uncontested)

g. What is a reasonable return on WEPCO's preferred stock? (Uncontested)

ENERGY EFFICIENCY

37. What are the appropriate 2010 escrow budgets? (Uncontested)

38. What are the appropriate measures of success for We Energies' customer service conservation activities? (Uncontested)

STEAM & ELECTRIC RATES

39. How should the steam rates, extension allowances, rules, and regulations be changed? (Uncontested)

Uncontested Alternative: Accept the changes in steam rates, extension allowances, service rules and regulations, and tariff sheet language shown in the utilities' exhibits adjusted to the final revenue requirement as shown in Exhibits 11.5 and 16.

40. Should a High and Low Pressure Steam and Condensate Return Service tariff be authorized for the Downtown Milwaukee steam utility (Ag-2) and what should be its rates? (Uncontested)

Uncontested Alternative: Accept the Downtown Milwaukee High and Low Pressure Steam and Condensate Return Service tariff with rates adjusted to the final revenue requirement as shown in Exhibits 11.5 and 16.

41. What cost-of-service study (COSS) and other factors should the Commission consider when allocating revenue responsibility?

Rate Case COSS Results				
Allocation	**Overall Increase**	**Small Use**	**Medium Use**	**Large Use**
WEPCO @ $218,205,000	8.4%	13.8%	-5.2%	4.3%
WEPCO Prorated @ $126,600,000	4.9%	8.0%	-3.0%	2.5%
WIEG – 4CP @$126,600,000	4.9%	12.8%	-8.3%	-1.5%
Staff Adjusted @$125,408,000	4.9%	8.9%	-8.2%	1.9%

The Commission has developed a policy of reviewing the results of several types of COSS and other factors when allocating revenue responsibility. (Petersen, Tr. D11.111)

In this docket the results of a variety of COSS are available for review. The discussion of differences in COSS methodology included:

- WEPCO's use of the Equivalent Peaker (EP) methodology to allocate production costs using both demand and energy allocators to allocate production plant and other production costs. The use of a 12 CP coincident peak demand allocator[1] instead of a 4 CP coincident peak demand allocator COSS to determine cost responsibility.

- The use of the minimum distribution system to define the appropriate level of distribution plant line cost that should be used to allocate those costs using customer-based allocators.

1 CP refers to coincident peak demand. A 12 CP allocator is calculated by averaging demand information drawn from each month of the year at the time of the highest coincident demand period of the utility. A 4 CP allocator is calculated using only information from the highest four monthly peaks of the year.

WEPCO, WIEG, and CUB all provided information on these topics. (Rogers, Tr. 219-228, R1.40-1.44; Baron Tr. D2.13-2.24, R2.3-2.8, SR2.2-3, SR2.7-2.8; WIEG Br. 11-13; and Edgar/DeForest Tr. 3.28-3.36, R3.4-3.9, SR 3.7-3.10)

The consideration of factors other than COSS results to assign revenue responsibility was raised. In its filing, WEPCO requested revenue less than might be justified by the costs it forecasted for test year 2010 and modified its COSS results and resulting revenue allocation and rate design to reflect this request. (Rogers, Tr. 240-241) WEPCO also submitted customer bill impacts. (Ex.52) Charter Steel and WIEG argued against a levelized increase in testimony using information on the negative impacts of increasing rates on Wisconsin manufacturing. (Baron, Tr. D2.7-D2.8 and Ertl, Tr. D12.6, SR 12.4) CUB stated that a substantial shift in costs has occurred due to the recession that is unprecedented and should be considered when determining the revenue allocation. (Edgar/DeForest Tr. D3.36-3.38, R3.2-3.3, SR3.7)

Alternative One: Continue the current Commission policy of reviewing the results of several types of COSS and other factors when allocating revenue responsibility.

Alternative Two: Adhere to COSS results when establishing revenue responsibility.

Alternative Three: Rely on factors other than COSS to establish revenue responsibility.

42. How should revenue responsibility be allocated to the WEPCO electric rate classes while maintaining authorized rate relationships?

WEPCO Rate Case Revenue Allocations				
Allocation	**Overall Increase**	**Small Use**	**Medium Use**	**Large Use**
WEPCO At $130,599,000 Increase				
COSS Based	5.0%	6.8%	4.9%	2.8%
Levelized	5.0%	4.9%	4.9%	5.2%
WIEG	4.9%	12.1%	-8.3%	2.5%
CUB – Equal kWh	4.9%	4.0%	4.4%	6.0 %
Staff Adjusted - $125,404,000 Increase				
COSS Based	4.9%	7.0%	3.4%	2.5%
Levelized	4.9%	4.9%	4.9%	4.9%

WEPCO and Commission staff each presented two approaches to revenue allocation. In the COSS-based allocation presented by each, the increase assigned to the Large Use class is below the overall average while the increase of Small Use customers is above average. However, increases do not adhere to COSS results and are closer to the overall average than a strict adherence to COSS results would dictate. In the "levelized" approach to revenue allocation presented by WEPCO and Commission staff, the customer class groups would receive a uniform percentage increase in revenue based on the revenue of the class. (Rogers, Tr. 240-241, SD 1.22, Ex. 50, and Petersen, Tr. D11.114-11.116, Ex. 11.4)

WIEG submits that Small Use customers should have a much larger than average increase than proposed by either WEPCO or Commission staff while Large Use customers should have a lower than average increase. To do so, WIEG asked that the Commission rely on the results of COSS to allocate revenue – specifically, the results of the 4 CP COSS it performed.

WIEG argued against a levelized increase for each rate class stating that such an allocation would ignore COSS results and be discriminatory to Large Use customers. (Baron, Tr. D2.7-2.12, 2.24, R2.2-2.4, 2.6, SR2.2-2.3; WIEG Br. 10-11; WIEG Reply Br. 3-5)

As previously noted Charter Steel also argued against a levelized increase and asked that the Commission continue to rely on the results of COSS and cited information on the negative impacts of increasing rates on Wisconsin manufacturing. (Ertl, Tr. D12.6, SR 12.4)

CUB argued that factors, such as drops in sales and the inappropriate allocation of costs, argues for a "levelized" revenue increase for all customers. However, CUB asserted that a uniform increase achieved through a uniform increase in energy charges of all classes is a better way to achieve a "levelized" increase than the uniform increase in class revenue as used by WEPCO or Commission staff. (Edgar/DeForest, Tr. D3.39-3.40, R3.2-3.5, CUB Br. 16P-17P, CUB Repley Br. 11-12) WIEG argued against using energy to achieve a "levelized" increase. (Baron, Tr. R2.6)

Alternative One: Authorize a below-average increase in revenue responsibility to the Large Use customer classes that reflects COSS results and other factors.

Alternative Two: Authorize a below-average increase in revenue responsibility to the Large Use customer classes that adheres to COSS results.

Alternative Three: Authorize a levelized percentage increase in revenue responsibility to all customer classes.

Alternative Four: Authorize increases in revenue responsibility to all customer classes based on a uniform kWh increase.

43. Should the Commission approve rate designs for the residential and small commercial flat rate and time-of-use (TOU) rate classes that collect relatively more revenue from energy charges and relatively less from customer charges?

Discussion

Commission staff witness Mr. Feit proposed a number of demand response options for consideration in this case. Mr. Feit suggested that there are several rate design changes that would encourage additional energy efficiency. One option would be to approve rate designs that collect relatively more revenue from energy charges and relatively less from customer charges for the residential and small commercial classes. (Feit, Tr. D11.26-27)

WEPCO believes that such a shift in revenue collection would unfairly shift costs from low usage customers to high usage customers and would have financial implications due to the uncertainty of sales forecasts. (Rogers, Tr. 150)

Decisions may regarding this issue may impact the issues relating to the tariff charges of the Small Use customer classes.

Alternative One: Approve rate designs for the residential and small commercial flat rate and TOU rate classes that collect relatively more revenue from energy charges and less from customer charges

Alternative Two: Do not make decisions relating to the level of customer charges with the objective of shifting revenue collection to energy charges.

44. How should the tariff charges of the Small Use class of customers be adjusted?

WEPCO proposed to increase the single-phase and three-phase facilities charges of Small Use classes with flat energy charges from $0.25000 per day to $0.25123 per day and from $0.50000 per day to $0.50246 per day. It also proposed to decrease the single-phase and three-phase facilities charges of Small Use classes with time-of-use (TOU) energy charges from $0.25000 per day to $0.20123 per day and from $0.50000 per day to $0.45256 per day. WEPCO supported the slight increases by stating that the facilities charges do not include all customer-related costs. (Rogers, Tr. 1.50) The justification for the lowering of the TOU facilities charges was stated as WEPCO's desire to create an incentive for Small Use customers to move to time-of-use rates. (Rogers, Tr. 243-244) The Commission staff alternative rate design seen in Exhibit 11.4 does not include an increase in flat-energy Small Use class facilities charges and lowers TOU class single-phase and three-phase facilities charges to $0.20000 per day and $0.45000 per day. This decrease is larger than proposed by WEPCO and could provide an even greater incentive for movement to TOU than offered by the WEPCO design. (Petersen, Tr. D11.116-D11.117)

CUB stated that the increase in flat-energy facilities charges is proposed to offset the lost revenue from the reduction in TOU charges. CUB avers that greater customer savings opportunities and better price signals will be reflected in more appropriate energy charges. (Edgar/DeForest, Tr. D3.41-D3.42)

The proposed Small Use class optional TOU energy charges of the WEPCO and Commission staff alternative rate designs have similar ratios of on-peak to off-peak energy charges for the for both the Level 1and Level 2 options, 2.2 and 5.2, respectively. (Rogers, Tr. 244-24; 5 Petersen, Tr. D11.116) The current ratios of Level 1and Level 2 are approximately 2.2 and 4.0, respectively. CUB disagreed with this TOU energy rate design approach. CUB states that on-peak and off-peak differentials are too high and do not properly reflect current costs, such as distribution costs, and future costs drivers, such as mitigating carbon emissions. Current Level 1and Level 2 on-peak and off-peak energy charge differentials are $0.09023 per kWh and $0.16263 per kWh, respectively. These differentials would increase to more than $0.10 per kWh and $0.20 in the WEPCO and Commission rate designs. The on-peak and off-peak energy charge differential for Large Use customers is about $0.02 per kWh. (Edgar/DeForest, Tr. D3.44-D3.46)

a. What should be the monthly facilities charges of Small Use classes with flat energy charges?

Alternative One: Increase the Small Use classes with flat energy charges single-phase and three-phase facilities charges to $0.25123 per day and $0.50246 per day, respectively.

Alternative Two: Do not change the single-phase and three-phase monthly facilities charges for Small Use customer classes with flat energy charges.

b. What should be the monthly facilities charges of Small Use classes with TOU energy charges?

Alternative One: Decrease the single-phase and three-phase facilities charges of Small classes with TOU energy charges to $0.20123 per day and $0.45256 per day, respectively.

Alternative Two: Decrease the single-phase and three-phase facilities charges of Small classes with TOU energy charges to $0.20000 per day and $0.45000 per day, respectively.

Alternative Three: Do not change the single-phase and three-phase monthly facilities charges Small Use customer classes with TOU energy charges.

c. How should the flat energy charges of the Small Use classes be adjusted? (Uncontested)

Uncontested Alternative: Adjust the flat energy charges of the Small Use classes as needed to achieve the assigned revenue requirement after facilities charges have been set.

d. How should the on-peak and off-peak energy charges of Small Use class optional TOU energy charges be adjusted?

Alternative One: Set the on-peak to off-peak time-of-use energy charge ratios at approximately 5.2 and 2.2 for the Rg-2 Level 1 and Rg-2 Level 2.

Alternative Two: Maintain the current differential in charges of the Rg-2 Level 1 and Rg-2 Level 2 TOU options.

e. How should the tariff charges of Lighting and all other Small Use class tariffs be adjusted? (Uncontested)

Uncontested Alternative: Authorize Lighting and other Small Use class tariff charges consistent with those shown in Exhibits 51 and 11.4 to achieve the revenue requirement.

45. Should the Commission approve rate designs for the demand/energy rate schedules of the Medium and Large Use customer classes that collect relatively more revenue from energy charges and relatively less revenue from demand charges?

Discussion

A second rate design policy alternative that would encourage additional energy efficiency would be to approve rate designs for the demand/energy rate classes that collect relatively more revenue from energy charges and less from demand charges. Mr. Feit testified that such a shift in revenue collection may be appropriate at this time given the capacity glut that exists in the Midwest and the significant amount of excess capacity that WEPCO has at this time. (Feit, Tr. D11.126-27)

Mr. Rogers testified that the current demand charges only reflect the capacity cost of a combustion turbine and transmission, that any reductions in demand charges are not warranted and that there is a reasonable limit below which capacity charges should not be reduced. (Rogers, Tr. R1.151-152)

Decisions regarding this issue may impact the issues relating to the tariff charges of the Medium and Large Use customer classes.

Alternative One: Approve rate designs for the demand/energy rate classes that collect relatively more revenue from energy charges and less from demand charges

Alternative Two: Do not make decisions relating to the level of demand charges with the objective of shifting revenue collection to energy charges.

46. How should be the tariff charges of the Medium Use class of customers? (Uncontested)

Uncontested Alternative: Establish tariff charges for the Medium Use class consistent with other decisions and the existing rate relationships with the tariff charges of the Small and Large class tariff charges.

47. Should the Commission authorize an optional TOU tariff for the General Secondary (Cg-2) class? (Uncontested)

Uncontested Alternative: Authorize an optional TOU tariff for the General Secondary (Cg-2) class.

48. Should the Commission order WEPCO to submit a plan to convert the Cg-2 commercial demand/energy rate schedule to a TOU rate?

Discussion

The Cg-2 demand/energy rate schedule was implemented about ten years ago as a bridge rate between the Cg-1 energy only rate and the Cg-3 large commercial rate. WEPCO has requested approval in this case for a voluntary TOU rate option for this schedule.

Mr. Feit proposed that the Cg-2 rate could be converted into mandatory TOU rate. However, such a change would require significant customer outreach and education. Mr. Feit proposed that the Commission could require WEPCO to submit a proposal by September 1, 2010, to convert the Cg-2 rate into a mandatory TOU rate with implementation at the beginning of 2011. (Feit, Tr. D11.128)

WEPCO witness Mr. Rogers testified that such a change would require significant study. Therefore, the utility proposes that it would be more appropriate to introduce such a rate in the next full rate case for a 2012 test year. (Rogers, Tr. R1.51)

Alternative One: OrderWEPCO to submit a proposal by September 1, 2010, to convert the Cg-2 demand/energy rate to a TOU rate.

Alternative Two: Order WEPCO to submit a proposal to convert the Cg-2 demand/energy rate to a TOU rate in its next rate case for a 2012 test year.

49. How should the Act 141 credits be calculated?

WEPCO submitted calculations for Residential and Non-residential Act 141 credits based on the manner in which Focus on Energy dollars are spent in its service territory, 47 percent Residential and 53 percent Non-Residential. (Rogers, Tr. 236, Sch. 5 Ex. 47) Commission staff used Wisconsin statewide Focus on Energy program spending averages of 40 percent residential and 60 percent Non-Residential and stated this provides consistency since the split of Act 141 program dollars will vary from utility to utility and from year to year and may not be known for all utilities. (Petersen, Tr. D11.117-D11.118, Ex. 11.4, Sch. 9)

Alternative One: Calculate Act 141 credits based on WEPCO territory Focus on Energy spending. (47 Residential/53 Non-Residential)

Alternative Two: Calculate Act 141 credits based on statewide Focus on Energy spending. (40 Residential/60 Non-Residential)

50. How should the tariff charges of the Large Use customer classes be adjusted? (Uncontested)

51. Should the Commission order WEPCO to submit an analysis of the costs to implement a dynamic pricing option for residential and small commercial customers within 90 days?

Discussion

CUB witnesses Messrs. Edgar and DeForest proposed a new voluntary rate for WEPCO's small customers. The rate would include a critical peak price for a limited number of hours, a flat energy charge for the remaining hours and a significant reduction in the customer charge. They believe that such a rate will provide a better price signal during high cost hours and allow the utility to better recover its costs. (Edgar/DeForest, Tr. D3.47-D3.50; CUB Init. Br. at 18-20)

WEPCO witness Mr. Rogers testified that the company's TOU rate and the experimental critical peak pricing and peak time rebate rate schedules it is currently offering to customers achieve most of the objectives that CUB is seeking. He also stated that WEPCO is willing to expand its rate offerings as the company evaluates customer responses to the current experimental programs. (Rogers, Tr. R1.49)

Alternative One: Order WEPCO to submit an analysis of the dynamic pricing option described by CUB.

Alternative Two: Do not order WEPCO to submit an analysis of the dynamic pricing option described by CUB.

52. Should the interruptible and curtailable credits be left at the current levels?

Discussion

In its proposed rate design, Mr. Rogers proposed to maintain the non-firm rate credits at their current levels. (Rogers, Tr. 247) The position was supported by Commission staff witness Mr. Feit, who testified that it would not be appropriate to increase the non-firm rate credits, given the current capacity surplus. (Feit, Tr. R11.2)

Mr. Baron, testifying on behalf of WIEG, argued that an increase in the non-firm credits is supported by WEPCO's non-firm capacity credit analysis shown in Mr. Rogers' Revised Exhibit 48. At a minimum, Mr. Baron argues that the non-firm credits should be increased by the same percentage as any increase that is authorized for the firm demand charges. (Baron, Tr. D2.26, WIEG Init. Br. 13)

Alternative One: Maintain the non-firm credits at the current levels.

Alternative Two: Increase the non-firm credits by the same percentage as firm demand charges.

53. Should WEPCO's non-firm rate schedules be closed to new customers?

Discussion

WEPCO witness Mr. Rogers testified that the utility is experiencing increasing interest in its curtailable and interruptible load programs because customers see little likelihood of interruptions given current capacity surplus. The utility proposed to close the existing non-firm rate schedules until there is no longer a capacity glut or until such time that the company can develop new non-firm rate programs that better reflect the MISO market. (Rogers, Tr. R1.52)

Alternative One: Approve WEPCO's proposal to close the non-firm rate schedules.

Alternative Two: Do not approve WEPCO's proposal to close the non-firm rate schedules.

54. Other Demand Response Options

a. Should the Commission order WEPCO to analyze and submit a plan to implement additional pricing periods for its large commercial and industrial TOU rate schedules?

Discussion

Mr. Feit testified that the current pricing periods for the TOU rate schedules were adopted more than thirty years ago. Mr. Feit proposed that the TOU rate structures would likely be more efficient if the on-peak and off-peak periods were split into additional pricing periods because the pricing would be more accurate. He proposed that the Commission order WEPCO to analyze this issue and submit a detailed proposal by September 1, 2010, with implementation in the beginning of 2011. (Feit, Tr. D11.27-28)

WEPCO is supportive of such a study but suggests that the Commission should wait to implement significant changes in the pricing periods until the utility's next full rate case. Rogers, Tr. R1.51.

Alternative One: Order WEPCO to analyze the issues associated with creating additional pricing periods for its demand/energy TOU rate schedules.

Alternative Two: Order such a study but do not consider implementation until WEPCO's next full rate case for a 2012 test year.

b. Should the Commission require WEPCO to develop a plan to bid its air conditioner direct load control program into the MISO energy market as price responsive load?

Discussion

Commission staff witness Mr. Feit testified that WPSC has bid its interruptible loads into the MISO energy market for several years as price sensitive load. Mr. Feit testified that price sensitive load would provide several benefits, including providing a better reflection of wholesale market prices to customers and reducing price volatility. He proposed that the Commission could require WEPCO to investigate the possibility of bidding its direct load program into the MISO energy market as price responsive load and into the MISO ancillary services market and submit a report to the Commission by September 1, 2010. Implementation could follow in 2011. (Feit, Tr. D11.29-D11.30)

WEPCO witness Eric Rogers testified that the utility is not opposed to this proposal, but has concerns about the details of bidding and the return of savings to customers. (Rogers, Tr. R1.52)

Alternative One: Order WEPCO to submit a proposal by September 1, 2010 to bid its air conditioner direct load control program into the MISO energy market as price responsive load.

Alternative Two: Do not order WEPCO to submit such a proposal.

c. Should the Commission require WEPCO to develop a plan to bid its interruptible load program into the MISO energy market as price responsive load?

Discussion

In a companion proposal, Mr. Feit also suggested that the Commission could order WEPCO to bid its interruptible loads into the MISO energy market as price responsive load. (Feit, Tr. D11.29-D11.30)

WEPCO is also not opposed to this proposal. (Rogers, Tr. R1.52)

Alternative One: Order WEPCO to develop a plan to bid its interruptible load program into the MISO energy market as price responsive load.

Alternative Two: Do not order WEPCO to develop such a plan.

55. What standard buyback rates should be authorized for purchases by the utility from customer-owned generation units? (Uncontested)

Uncontested Alternative: Authorize the rates as indicated in Exhibit 48.

56. What changes should be made in the customer-owned generation buy-back tariffs? (Uncontested)

Uncontested Alternative: Eliminate the existing CGS1 and CGS2 tariffs and replace these tariffs with a new CGS1 based on LMP and new CGS6 (Renewable) and CGS7 (Non-Renewable) buy-back tariff offerings.

57. What changes in electric embedded credits and electric rate, service rule, and extension rule tariffs should be authorized? (Uncontested)

Uncontested Alternative: Authorize electric embedded credits and electric rate, service rule, and extension rule tariffs as indicated in Exhibit 54 after updating for other decisions may by the Commission.

58. Should the remainder of Point Beach Sale net proceeds be returned to customers in 2010 in the manner directed in the order in docket 5-UR-103? (Uncontested)

Uncontested Alternative: Return the remainder of Point Beach Sale net proceeds to customers in 2010 as directed in the Final Decision in docket 5-UR-103.

NATURAL GAS COST-OF-SERVICE AND NATURAL GAS RATES

59. What COSS should the Commission consider when allocating revenue responsibility?

Discussion

Robert E. Jacobson on behalf of the Companies and Commission staff rate analyst Robert Bauer prepared natural gas COSS in this proceeding. Mr. Bauer prepared two COSS to establish a range of reasonableness. Mr. Jacobson's COSS and Mr. Bauer's COSS A are customer-oriented studies and Mr. Bauer's COSS B is a commodity-oriented study. Customer-oriented studies generally result in higher costs to low-volume service rate classes and lower costs to large-volume service rate classes, when compared to the results of commodity-oriented COSS. Mr. Jacobson's COSS and Mr. Bauer's COSS A differ given the number of allocations that are based on individual judgment factors, but these differences were difficult to identify given the revenue requirement differences and the lack of COSS detail that would be necessary to perform a comparative analysis of two studies. However, neither Mr. Jacobson nor Mr. Bauer expressed concerns with the methodology employed with the other's customer-oriented COSS.

Mr. Bauer stated that COSS A and B provide the bookends of a range of reasonableness for rate design and indicated that in past rate cases, the Commission has found that one objectively "correct" standard or COSS does not exist. He testified that COSS A and B are consistent with the Commission's policy and represent a guide to setting rates. (Bauer, Tr. D11.136-D11.137)

Mr. Bauer stated that proponents of COSS B argue that: (1) Mains are installed to deliver volumes of gas and are sized to meet system peak day demands; (2) Mains are also installed to improve system reliability; and (3) Mains are not generally dedicated to individual customers. Therefore, the proponents conclude that costs associated with the investment and maintenance of mains should be allocated to the service classes based on commodity and demand. (Bauer, Tr. D11.136)

Alternative One: Consider the customer-oriented COSS of the Companies or Commission Staff, or both, when determining final rates for natural gas service.

Alternative Two: Rely on several different COSS, as well as other factors, when determining final rates for natural gas service.

60. Should fixed charges recover more of the distribution margin costs from the residential and the G-1 commercial service rate classes?

Background

Distribution service charges recover the cost of moving gas from the point of local supply to the customer’s meter. These charges are applicable for all customers and charges for either system sales service or transportation service would be an additional charge. Distribution service charges for small-volume service include a fixed distribution service charge and a volumetric (per therm) distribution charge. Over the course of several rate cases, Wisconsin natural gas utilities have consistently proposed rate designs with greater reliance on fixed customer charges than on volumetric distribution charges to attain the required revenue. Wisconsin natural gas utilities argue that fixed costs should be recovered from fixed charges and they have indicated that fixed charges are more desirable because fixed charges provide more revenue stability than do volumetric charges.

Discussion

Mr. Korducki on behalf of the companies proposed residential rates that put more emphasis on cost recovery by means of fixed rate elements in order to better align the fixed/variable revenue composition with the fixed/variable composition of the companies' costs. (Korducki, Tr. 193-194)

Mr. Bauer proposed smaller increases in the fixed residential service charges. Commission staff charges are designed to recover customer costs including meter reading, billing and collecting expenses, and the depreciation and return costs associated with meter and service laterals. (Bauer, Tr. D11.147)

CUB opposed increases in the fixed residential customer charges and argued that increasing current fixed charges would not provide a useful price signal about the future costs of a customer's current consumption especially in light of global warming considerations, and it would not provide any useful information, especially to existing customers, about whether they should continue to take or use gas service. Finally, increasing the fixed charges will diminish the benefits that a customer will receive from reducing their consumption through energy conservation or efficiency. (CUB, Tr. R3.12)

Commission staff stated that it is possible for customers to use so little gas that service availability costs exceed billing charges. However, if the customer believes that the higher fixed customer service charges make the use of gas unattractive, then the customer should terminate gas service and use an alternative energy. (Bauer, Tr. SR11.27-SR11.28)

Below are the current and proposed fixed and total volumetric residential service charges:

Description	WE-GO[2] Present	Company Proposal Amount	Company Proposal Increase	Staff Proposal Amount	Staff Proposal Increase
Fixed Charge	$ 8.52	$ 10.04	17.84%	$ 8.82	3.52%
Volumetric Charges	$ 0.2124	$ 0.2335	9.93%	$ 0.2118	(0.28%)

Description	WG[1] Present	Company Proposal Amount	Company Proposal Increase	Staff Proposal Amount	Staff Proposal Increase
Fixed Charge	$ 8.52	$ 10.04	17.84%	$ 9.43	10.68%
Volumetric Charges	$ 0.2616	$ 0.2856	9.17%	$ 0.2662	1.76%

Madison Gas and Electric Company[1] and Northern States Power Company–Wisconsin have fixed monthly residential customer service charges equal to $10.25. Midwest Natural Gas Incorporated has a fixed monthly residential service charge equal to $9.50. Wisconsin Public Service Corporation decreased its fixed monthly residential customer service charge from $10.25 to $7.00 when it adopted a residential revenue stabilization mechanism. (Bauer, Tr. SR11.28)

Alternative One: Increase the fixed distribution margin rates for the residential and G-1 commercial service rate classes to the Companies' proposed levels.

Alternative Two: Increase the fixed distribution margin rates for the residential and G-1 commercial service rate classes to Commission staff's proposed levels.

Alternative Three: Do not increase the fixed distribution margin rates for the residential and G-1 commercial service rate classes.

61. Should WE-GO's Fixed Daily Transportation Administrative Charge be reduced to $2.00 per day? (Uncontested)

62. Should the Companies merge the two largest volume rate customer classes, G-7 and G-8, into a single customer class? (Uncontested)

[2] Tariffs set forth daily fixed charges. For discussion and comparative purposes, the amounts are expressed as an average amount per month.

63. Should the Companies revise the volumetric customer classifications for agricultural service from an annual provision to a moving three-year average provision and change the effective date of reclassifications from November 1 to September 1? (Uncontested)

64. Should WG continue grandfathering interruptible service, IG-3, to current subscribers? (Uncontested)

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